ENERGY RESOURCES

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The Energy Resources Program (ER) is responsible for two major program areas: Oil and Gas Exploration and Development, and Geothermal Energy Development.

OIL AND GAS EXPLORATION AND DEVELOPMENT

Multidisciplinary research is being conducted in reservoir characterization and monitoring, optimization of reservoir performance, and environmental protection. Using basic research studies as a source of innovative concepts, ER researchers seek to transform these concepts into tangible products of use to industry within a time frame consistent with today's rapid growth in technology. Reservoir characterization and monitoring involve development of new seismic and electromagnetic techniques focused at the interwell scale. Field acquisition, laboratory measurements, and numerical simulation play important roles in the development activities. Optimization of reservoir performance is focused on simulation-based methods for enhancing reservoir management strategies. Emphasis is placed on the integration of geophysical data, production data, and reservoir simulation. The next major step in research will focus on methods to optimize performance through integration of monitored geophysical data, production data, and reservoir simulation.

International and national concern about the variable climatic effects of greenhouse gases produced by burning of fossil fuels is increasing, while it is also recognized that these fuels will remain a significant energy source well into the 21st century. In response to these concerns, ER has initiated research focused on development of technologies that will minimize the impact of fossil-fuel usage on the environment.

Methane hydrates constitute a tremendous potential fuel source with lower carbon emissions than coal or oil. ER researchers are developing and evaluating possible methods for producing gas from such deposits. Geophysical data acquisition and inversion methods developed in the ER program are also being applied in a new project on geologic sequestration of CO_2 carried out in the Climate Change and Carbon Management Program within the Earth Sciences Division.

Principal research activities include:

- Development of microwell seismic technology, including instrumentation, acquisition, and processing
- Applications of seismic methods for characterization of fractured reservoirs
- Laboratory measurement of the seismic properties of poorly consolidated sands
- Evaluation of seismic stimulation methods and their application to different classes of oil reservoirs
- Improved inversion methods for reservoir characterization, with a focus on combining production and geophysical data
- Application of x-ray computed tomography and nuclear magnetic resonance imaging to study multiphase flow processes
- Pore-to-laboratory-scale study of physical properties and processes, with a focus on controlling phase mobility, predicting multiphase flow properties, and increasing drilling efficiency
- Development of new methods to mitigate environmental effects of petroleum refining and use
- Enhancement of refining processes using biological technologies
- Numerical simulation of subsurface methane hydrate systems

Since 1994, the major part of the Oil and Gas Exploration and Development program has been funded through the

Natural Gas and Oil Technology Partnership Program. Begun in 1989, the partnership was expanded in 1994 and again in 1995 to include all nine Department of Energy multiprogram laboratories, and has grown over the years to become an important part of the DOE Oil and Gas Technologies program for the national laboratories. Partnership goals are to develop and transfer to the domestic oil industry the new technologies needed to produce more oil and gas from the nation's aging, mature domestic oil fields, while safeguarding the environment.

Partnership technology areas are:
- Oil and gas recovery technology
- Diagnostics and imaging technology
- Drilling, completion, and stimulation
- Environmental technologies
- Downstream technologies

GEOTHERMAL ENERGY DEVELOPMENT

There are two main objectives of ER's geothermal energy development program: (1) to reduce uncertainties associated with finding, characterizing, and evaluating geothermal resources, and (2) to develop and understand the enhancement of current geothermal systems to significantly increase production. The ultimate purpose is to lower the cost of geothermal energy for electrical generation or direct uses (e.g., agricultural and industrial applications, aquaculture, balneology). The program encompasses theoretical, laboratory, and field studies, with an emphasis on a multidisciplinary approach to solving the problems at hand. Existing tools and methodologies are upgraded, and new techniques and instrumentation are developed for use in the areas of geology, geophysics, geochemistry, and reservoir engineering. Cooperative work with industry, universities, and government agencies draws from Berkeley Lab's 25 years of experience in the area of geothermal research and development.

In recent years, DOE's geothermal program has become more industry-driven, and the Berkeley Lab effort has been directed toward technology transfer and furthering our understanding of the nature and dynamics of geothermal resources under production.

At present, the main research activities of the program include:
- Geothermal Reservoir Dynamics: development and enhancement of computer codes for modeling heat and mass transfer in porous and fractured rocks, with specific projects such as modeling the migration of phase-partitioning tracers in boiling geothermal systems; modeling

of mineral dissolution and precipitation during natural evolution, production, and injection operations; and geophysical-signature prediction of reservoir conditions and processes
- Isotope Geochemistry: identification of past and present heat and fluid sources, development of natural tracers for monitoring fluids re-injected into geothermal reservoirs, better understanding of the transition from magmatic to geothermal production fluids, and enhancement of reservoir-simulation methods and models by providing isotopic and chemical constraints on fluid source, mixing, and flow paths
- Geochemical Baseline Studies: documentation of geothermal-fluid behavior under commercial production and injection operations (e.g., field case studies), with specific emphasis on The Geysers field in Northern California
- Electromagnetic Methods for Geothermal Exploration: development of efficient numerical codes for mapping high-permeability zones, using single-hole electromagnetic data

Future research will concentrate on the development of innovative techniques for geothermal exploration and assisting in a reassessment of geothermal power potential in the U.S. The emphasis will be on expanding existing fields, prolonging their productive life, and finding new "blind" geothermal systems, i.e., those that do not have any surface manifestations, such as hot springs, fumaroles, etc., that suggest the presence of deeper hydrothermal systems.

FUNDING

http://www-esd.lbl.gov/

A Stochastic Model for Base-Of-Salt Mapping Using Gravity Data

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RESEARCH OBJECTIVES

Mapping base-of–salt using gravity and gravity gradient data is subject to a large degree of uncertainty, because of measurement errors and ambiguity in those data. Deterministic methods are limited for characterizing this uncertainty, since the optimal estimates of base-of-salt rely on starting models, and sensitivity-analysis methods often underestimate the actual uncertainty in the estimation. Our goal in this study is to develop a stochastic model for mapping base-of-salt using gravity and gravity-gradient data. The model should provide not only the estimates of base-of-salt at each location, but also uncertainty information at the location, such as mean, variance, ranges, and possible multiple modes.

APPROACH

In this study, we assume that the seafloor and top-of-salt of a continuous salt body are known through seismic surveys. We consider the thickness of the salt body at each location in the area as a random variable and strive to estimate the probability distribution function (instead of a single value) of the thickness, using gravity and gravity-gradient data. First, we define a joint posterior probability distribution function for all the unknown thicknesses, using a Bayesian framework. Second, we develop a Markov chain Monte Carlo (MCMC) method to obtain many samples of each unknown variable. Finally, we estimate the mean, variance, density function, and predictive intervals of each unknown variable. We also compare the results obtained using stochastic models with those obtained using deterministic methods.

ACCOMPLISHMENTS

We tested our stochastic model using a simple synthetic data set, based on a seismic model of a Gulf of Mexico site (Gemini) with one salt body, and a field data set collected from a North Sea site. We also explored the efficiencies of a variety of sampling methods, which included methods using gradient information, methods updating by columns, and methods updating by blocks. An image based on the Gemini data set is shown in Figure 1. Salt thickness uncertainty information at four locations is shown in Figure 2, where locations were chosen at which the estimated thickness of salt is distributed bi-modally, with intermediate thickness less likely, given the measured gravity and gravity gradient data.
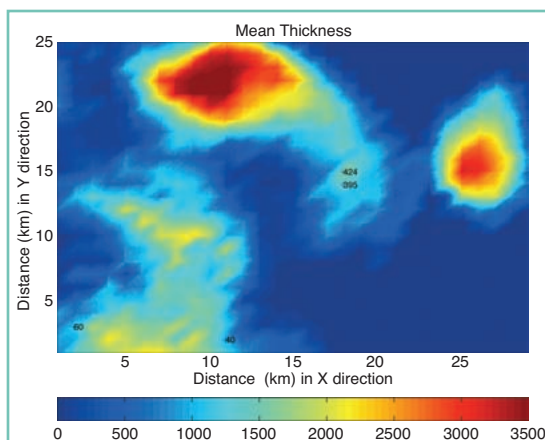

Figure 1. The estimated thickness of the salt body based on data collected from the Gemini data set. The numbers in the image show several locations where the thickness may have bi-modes.
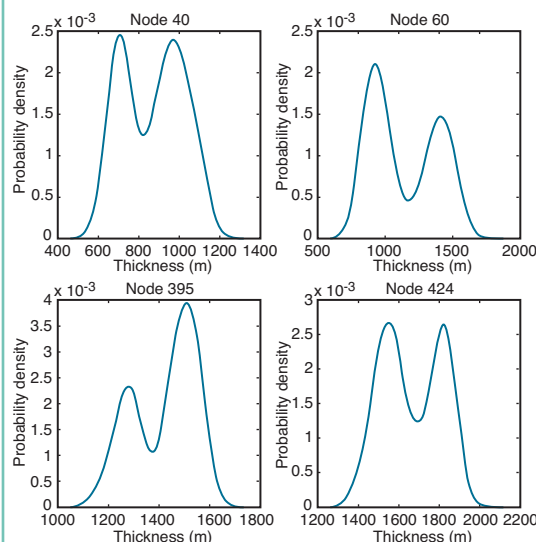
Figure 2. Probability densities for the salt-body thicknesses at the four locations, where the thickness may have bi-modes

SIGNIFICANCE OF FINDINGS

Our stochastic model for mapping base-of-salt provides an effective approach for characterizing uncertainty in the estimation of base-of-salt, since it gives us not only the estimates of base-of-salt but also the possible modes, ranges, and distributions at the location. The stochastic model, if used together with a deterministic model, can significantly reduce the number of forward calculations needed for the MCMC sampling method. For example, we can start from the optimal solutions obtained from deterministic models and draw many samples from the initial values.

RELATED PUBLICATION

Chen, J., M. Hoversten, and T. Smith, Stochastic inversion of gravity data for mapping the base-of-salt. Geophysics (in preparation), 2005.

ACKNOWLEDGMENTS

SIMULATION OF RESERVOIR ROCK FORMATION: SEDIMENTATION, COMPACTION, AND DIAGENESIS

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RESEARCH OBJECTIVES

The microstructure of sedimentary rock determines its transport, electric, and mechanical properties. An efficient rock modeling procedure would enable characterization of the pore space geometry and compute the desired macroscopic properties of the rock. The objective of this project is to develop methods for modeling the formation of sedimentary rocks suitable for prediction of rock-transport properties directly from analysis of microscopic pore-space geometry.

APPROACH

The dynamic geologic processes of grain sedimentation and compaction are simulated by solving a dimensionless form of Newton's equations of motion for an ensemble of grains. The Lattice-Boltzmann method is used to simulate viscous fluid flow in the pore space of natural and computer-generated rock samples.
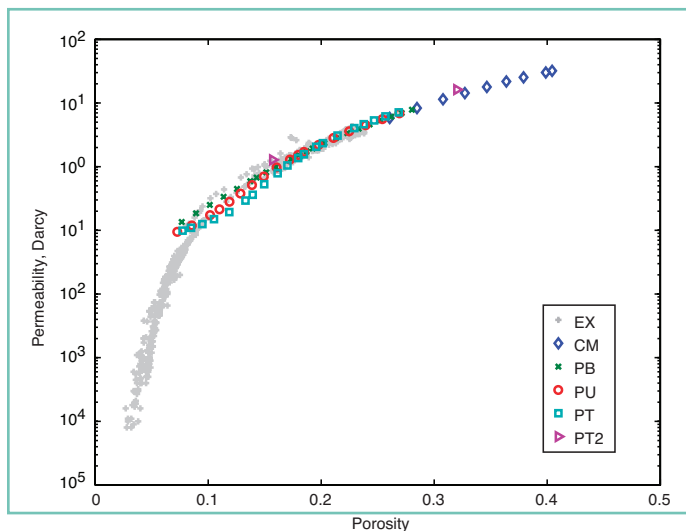

Figure 1. The evolution of absolute permeability of the modeled unconsolidated Fontainebleau sandstone with progressive compaction (CM), various modes of cementation (PB, PU, and PT), and different diagenetic history (PT and PT2), and the measurements on the real Fontainebleau sandstones

ACCOMPLISHMENTS

An integrated approach for estimating the absolute permeability of unconsolidated and consolidated reservoir rock has been developed. This procedure consists of two major steps: (1) obtaining an image from a computed tomography (CT) scanner or simulation of sedimentary rock formation; and (2) simulating viscous fluid flow in the pore space of a tomographic or computer-generated rock image. The results are confirmed by the quantitative comparison of computed permeability with experimental data. The computations-based porosity-permeability relationship of the modeled Fontainebleau sandstone is in good agreement with the laboratory measurements in real rocks (Figure 1).

SIGNIFICANCE OF FINDINGS

Our approach can be used to study the evolution of sedimentary rock porosity, permeability, and strength during arbitrary rock deformations and fracturing. The obtained knowledge can be used to predict rock properties from the grain size distribution and diagenetic history. The crucial factors controlling rock properties can be identified by running various "what-if" simulations. Our model is particularly suitable for analysis of unconsolidated sands whose cores or microtomographic images cannot be obtained.

RELATED PUBLICATIONS

Jin, G., T. Patzek, and D. Silin, Dynamic reconstruction of sedimentary rock using the distinct element method. SPE Journal (submitted), 2004. Berkeley Lab Report LBNL-55038.

Jin, G., T. Patzek, and D. Silin, Direct prediction of the absolute permeability of unconsolidated and consolidated reservoir rock. SPE Paper 90084, Presented at SPE Annual Technical Conference and Exhibition, Houston, Texas, 2004. Berkeley Lab Report LBNL-55339.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

MEASURING AND OBSERVING METHANE HYDRATE BEHAVIOR UNDER NATURAL CONDITIONS

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RESEARCH OBJECTIVES

Naturally available gas hydrates present in suboceanic and permafrost environments are thought to contain a vast amount of natural gas, amounts that could eventually be exploited as an energy source. Efficiently tapping this incompletely comprehended energy source will require strong modeling capabilities and significant laboratory and field efforts to determine modeling parameters and constitutive models. Natural samples are difficult to obtain for testing purposes because the hydrates are unstable at atmospheric pressure and typically dissociate upon recovery.

Our research objective is to provide model parameters and constitutive models for the Berkeley Lab simulator TOUGH-Fx/HYDRATE. To do this, we make laboratory measurements under realistic conditions on samples of hydrate in porous media, which we synthesize to model natural samples. Monitoring pressure and temperature, we use x-ray computed tomography (CT) to make detailed observations of density changes during tests.

APPROACH

We synthesize large methane hydrate samples in partially water-saturated sand samples in an x-ray-transparent pressure vessel contained within a temperature-controlled heat exchanger. Temperature is monitored at multiple locations, pressure is monitored during hydrate synthesis and dissociation tests, and we use CT to monitor density changes that occur in response to changes in temperature and pressure.

ACCOMPLISHMENTS

We have synthesized methane hydrate in the pore space between mineral grains, with our samples being the largest laboratory samples in the world. We have dissociated the hydrate by both thermal stimulation and depressurization, and have used our measurements to determine the thermal conductivity of the

hydrate-bearing medium, and to estimate the parameters of dissociation kinetics. From this work, we have learned that the presence of hydrate in the pore space alters the capillary pressure-saturation curve affecting water movement, and that formation and dissociation of hydrate in partially saturated sand may induce mechanical changes that cause the sample size to change (Figure 1).

SIGNIFICANCE OF FINDINGS

We have begun to develop parameters and constitutive models that are useable to model gas production from hydrate accumulations, in addition to observing processes via CT. We are the first to use CT to quantitatively measure changes during hydrate formation and dissociation, leading to improvements in conceptual models.

RELATED PUBLICATIONS

Kneafsey, T.J., L. Tomutsa, G.J. Moridis, Y. Seol, B. Freifeld, C.E. Taylor, and A. Gupta, Methane hydrate formation and dissociation in a partially saturated core-scale sand sample. Journal of Petroleum Science and Engineering (submitted), April 2005. Berkeley Lab Report LBNL-57300.

Moridis, G.J., Y. Seol, and T.J. Kneafsey, Studies of reaction kinetics of methane hydrate dissociation in porous media. In: Fifth International Conference on Gas Hydrates, Trondheim, Norway, 2005. Berkeley Lab Report LBNL 57298.
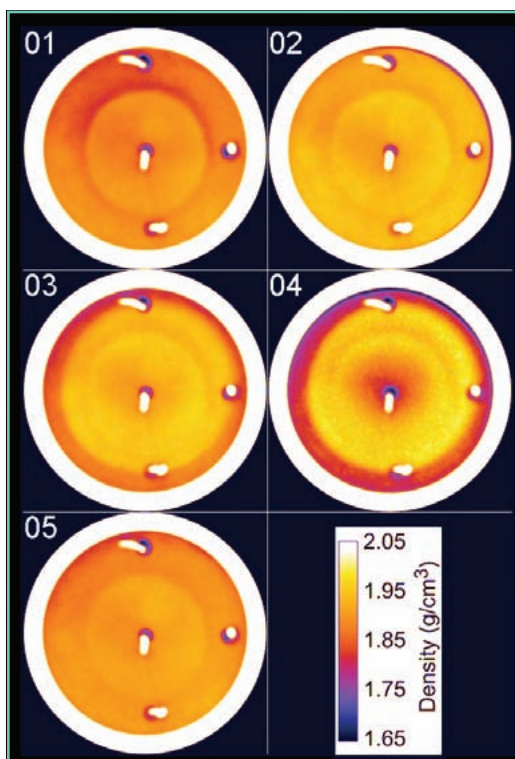
ACKNOWLEDGMENTS

Figure 1. CT scans showing the average density in the 7.6 cm diameter x 26 cm cylindrical sample: (1) initial condition, (2) after hydrate formation, (3) after thermal stimulation from the outside, (4) after secondary hydrate formation, and (5) after complete dissociation. Note the dark rind at the upper right contact between the vessel (white circle) and the sample inside, indicating sample shrinkage on hydrate formation in (2) and (4). The short white lines within the white circle are thermocouples.

DETECTION OF HIDDEN GEOTHERMAL SYSTEMS BASED ON NEAR-SURFACE CO$_2$

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RESEARCH OBJECTIVES

The majority of hydrothermal systems with obvious surface expressions in the U.S. have been explored to determine their development potential. Consequently, discovery of new geothermal systems will require exploration of areas where the resources are hidden. Emissions of moderate-to-low solubility gases may be one of the primary near-surface signals from hidden geothermal systems, and detection of anomalous gas emissions may be a tool by which to discover new resources. Carbon dioxide shows promise because it is the major noncondensible gas present in geothermal systems, has moderate solubility in groundwater, and is measurable by numerous technologies. The objective of this work is to design an integrated measurement, modeling, and analysis strategy to identify geothermal CO$_2$ in the near-surface environment, with the goal of discovering hidden geothermal systems.
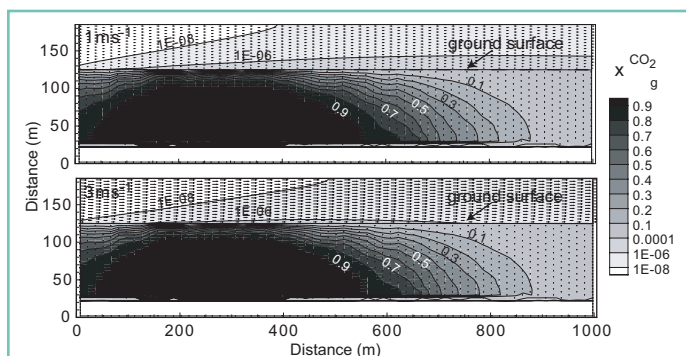

Figure 1. Coupled CO$_2$ subsurface migration and surface-layer mixing at t = 200 years for one heterogeneous permeability realization, source CO$_2$ flux = 576 g m^{-2} d^{-1}, and constant wind speeds of 1 m s^{-1} (upper plot) and 3 m s^{-1} (lower plot). CO$_2$ concentration is in mole fraction.

APPROACH

Simulations were conducted using the numerical code T2CA, a coupled subsurface-atmospheric surface layer flow and transport model, to estimate near-surface CO$_2$ concentrations and fluxes that might result when CO$_2$ leaks from a hidden geothermal system at depth. The geologic framework of the modeled hidden geothermal system was based on an arid Basin and Range Province system. Observed sources, as well as the spatial and temporal variability of natural background CO$_2$ fluxes and concentrations in the near-surface environment, were also evaluated. Methods were designed to detect geothermal CO$_2$ emissions within the background variability of CO$_2$, integrating field measurement technologies with statistical analysis and modeling approaches.

ACCOMPLISHMENTS

Near-surface CO$_2$ fluxes and concentrations were simulated for different geothermal source CO$_2$ fluxes, homogeneous and heterogeneous permeability structures, and constant wind speeds. Results show that CO$_2$ concentrations can reach high levels in the shallow subsurface, even for relatively low geothermal source CO$_2$ fluxes (Figure 1). However, winds are effective at dispersing CO$_2$ seepage. Technologies to detect CO$_2$ in the near-surface were evaluated for detection capability and cost. An exploration strategy was proposed involving integrated measurement, modeling, and statistical analysis to characterize the spatial and temporal variability and source of CO$_2$ in a background system and the area targeted for exploration. Emphasis was placed on using time- and cost-efficient methods to determine whether CO$_2$ derived from a geothermal source is present, and if so, the spatial extent of the anomaly.

SIGNIFICANCE OF FINDINGS

The proposed near-surface CO$_2$ monitoring and analysis strategy is designed to search for relatively small geothermal CO$_2$ signals within the background variability of CO$_2$, using relatively low-cost and time-efficient methods. Further geophysical measurements, installation of deep wells, and geochemical analyses of deep fluids can be guided by the results of the near-surface CO$_2$ investigation.

RELATED PUBLICATION

Lewicki, J.L., and C.M. Oldenburg, Near-surface CO$_2$ monitoring and analysis to detect hidden geothermal systems. Proceedings, 30th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 2005. Berkeley Lab Report LBNL-56900.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

THE APPLICATION AND USE OF MICRODRILLING FOR VERTICAL SEISMIC PROFILING AND MONITORING RESERVOIR PERFORMANCE

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RESEARCH OBJECTIVES

Microhole technology (providing inexpensive access to the subsurface) has the potential to be the most significant technology advance for the energy industry in the last 50 years. It has the potential to be a catalyst for creating a quantum leap in imaging technology, which could lead to a much clearer understanding of subsurface processes. A critical application is the placement of sensors in the subsurface for use with seismic techniques such as vertical seismic profiling (VSP), crosswell, microseismic, and even high-resolution surface seismic to image and monitor previously unknown or unresolved resources. To achieve this goal, we are pursuing an integrated program of testing, evaluation, and development of the technology required to deliver, process, and interpret the data.

APPROACH

The technology exists today to achieve many of these goals. To a large degree, it is a matter of tailoring this technology for the energy industry rather than starting from scratch. The DOE National Energy Technology Laboratory (NETL) oil program has undertaken and sponsored an integrated program of modeling, instrumentation evaluation/testing, and data acquisition and processing. This effort is tightly coupled with the microdrilling program at Los Alamos National Laboratory (LANL), and with field testing at the Rocky Mountain Oil Testing Center (RMOTC) at Teapot Dome in Wyoming (as well as at other sites of opportunity), to test and develop the technology. In the first year, the focus of the effort was modeling, design, and processing of multiple shallow VSP's (500 to 700 ft deep) in microdrilled holes within a well-characterized area. Follow-on tasks extended this work, with continued evaluation of sensors for use in microholes, optimizing the employment of sensors using innovative clamping and deployment mechanisms, partnering with industry for data acquisition and sensor evaluation, and processing/interpreting data derived from field tests.

ACCOMPLISHMENTS

In 2004 and early 2005, Berkeley Lab deployed a 20-level (with 5 m spacing) hydrophone and geophone string in the 750 ft deep microhole that LANL drilled at RMOTC. The purpose was to compare the difference between a fluid coupled sensor and a directly clamped sensor. The overall objective, however, was to determine the image volume and resolution that could be obtained from microholes drilled to depths above a target. For example, most VSP wells are drilled to the target or just above a target. In this case, our target was 1,500 ft (two well depths) below the well. Because of the small size of the microholes, a new type of clamping system had to be developed for the geophones. This "vacuum assisted" clamping mechanism is

used to minimize the overall size of the package such that it will fit down the well. Another prime objective was to develop low-cost instrumentation that could be deployed in a low-cost manner (most VSP surveys cost from 50 K to 250 K per well to collect the data). Modeling of the shot-hole locations was performed prior to the field work to estimate shot spacing, total distance for the well, etc. Two complete VSP multi-offset (12 shot locations each) with offset distances from 35 ft to 2,700 ft (every 250 ft) were completed using a 20-level hydrophone string and a 20-level geophone string. In total, 40 levels were recorded for each set of sensors, using 12 different shot locations. A vibroseis was used as a source (Enviroseis from IVI Inc.) to minimize ground disturbance and maximize its high-frequency content (up to 300 Hz). Figure 1 shows one of the VSP results from the survey. As can be seen, the reflections are coming from well below the target depth. This was a relatively near offset, but it does show good reflections.
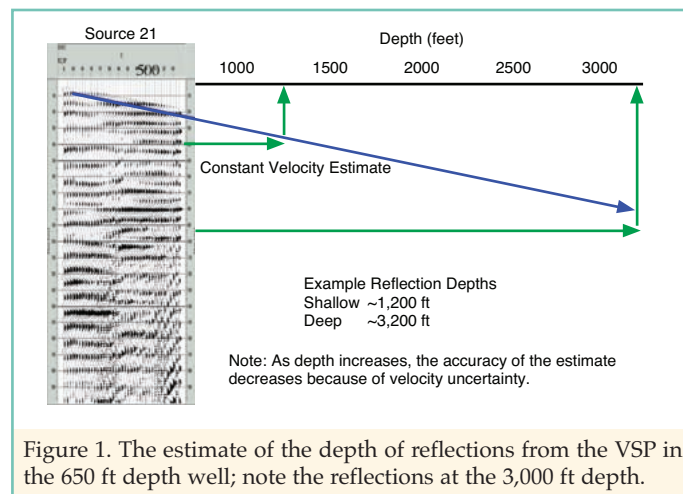

Figure 1. The estimate of the depth of reflections from the VSP in the 650 ft depth well; note the reflections at the 3,000 ft depth.

SIGNIFICANCE OF FINDINGS

All objectives were met in the evaluation of the microhole technology for VSP. In addition, a baseline study was obtained in preparation for future CO_2 injection monitoring. Direct arrivals were observable from source offsets of 2,800 ft, and reflections were observable as deep as 3,000 ft. As more microholes are drilled, additional data can be acquired to expand the image to accommodate larger CO_2 injections.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

Evaluating and Managing the Impact of Induced Seismicity at the Geysers Geothermal Field

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RESEARCH OBJECTIVES

As the demand for energy increases, it is obvious that geo-thermal resources must play a growing part in meeting our energy needs. Water injection into geothermal systems, to affect enhanced geothermal systems (EGS), has become an often-required strategy to extend and sustain production of geothermal resources. Critical questions that need to be addressed are how injection will affect seismicity of an area, what does seismicity imply for injection strategy, and how will seismicity and injection together impact the local community, as well as field operations.

The two prime objectives of this project are: (1) to understand the impact of EGS operations on induced seismicity and its environmental impact on the surrounding community, and (2) to use microearthquake monitoring to intelligently manage the effects of fluid injections and stimulations, so as to ensure the optimization of EGS projects.

APPROACH

The Geysers, in Sonoma County, California, is a prime candidate for EGS because of its very high heat content—injection is one of the few economic means by which to mine the heat stored there in the subsurface rock. This site constitutes a unique opportunity for obtaining data before injection and increased production begin. Additional opportunities exist in the Basin and Range to monitor seismicity associated with hydrofracturing and using microearthquake (MEQ) monitoring to track the induced fracturing. In addition to natural fracture systems, hydrofracturing may be a possible means to enhance the fracture area and permeability of geothermal reservoirs. MEQ monitoring is a means to track the hydrofracture and estimate the success of the hydrofracturing operations.

Besides collecting data to address the environmental impact of EGS operations, we are also part of an International Energy Agency implementing agreement to participate in assessing and mitigating the environmental effects of these operations, specifically induced seismicity. The work scope of this international group is "to pursue a collaborative effort to address an issue of significant concern to the acceptance of geothermal energy in general, and EGS in particular. The objective is to investigate these (induced) events to obtain a better understanding of why they occur, so that they can either be avoided or mitigated. Understanding requires considerable effort to assess and generate an appropriate source-parameter model, testing of the model, and then calculating the source parameters in relation to the hydraulic injection history, stress field and the geological background. An interaction between stress modeling, rock mechanics, and source-parameter calculation is essential. Once the mechanism of the events is understood, the injection process, the creation of an engineered [enhanced] geothermal reservoir, or the extraction of heat over a prolonged period may need to be modified to reduce or eliminate the occurrence of large [seismic] events."

ACCOMPLISHMENTS

Data are being routinely gathered and analyzed in real time and sent to the U.S. Geological Survey for archiving. Figure 1, a typical map of a month's seismicity at The Geysers, shows the lack of seismicity in the northwest Geysers (Aidlin area), where injection has not yet started. Results will include a unique data set for a geo-thermal area, a set that will be available to the public and research community. Initial correlation has shown that although the numbers of events are increasing at The Geysers, the overall energy release is level or decreasing (do EGS areas eventually gain stability?). Also, as can be seen from Figure 1, the larger events occur outside of the main clusters (green stars).
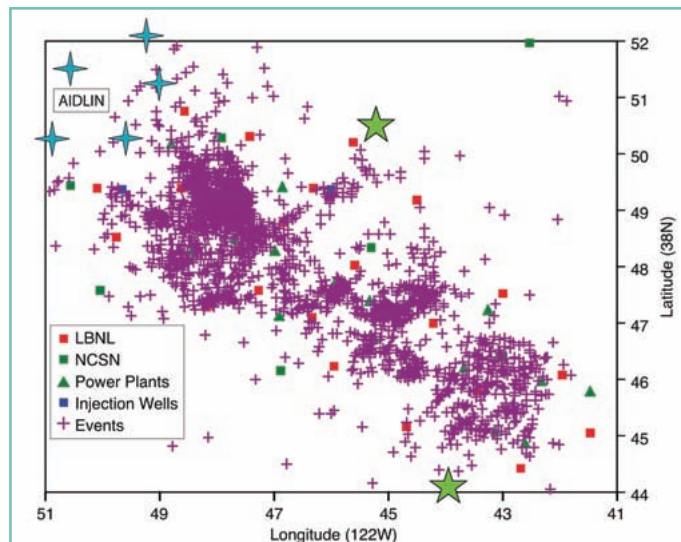

Figure 1. Locations of events in Nov. of 2004, Geysers wide—note the lack of events in the Aidlin area prior to high-rate injection; injection will proceed in the fall/early winter of 2005. The Blue stars are the new Berkeley Lab stations installed in FY 04. Green stars are Magnitude 4 events (February 2004, December 2004).

SIGNIFICANCE OF FINDINGS

Never-before resolution and coverage will allow detailed analysis to correlate and investigate the link of induced seismicity to injection and production at The Geysers. Real-time public display will allow the community to gain confidence and assurance that the operators are acting in a responsible fashion.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

APPLICATION OF SEISMIC METHODS FOR FRACTURE CHARACTERIZATION

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RESEARCH OBJECTIVES

A five-year (2000–2004), comprehensive, joint industry, university, and national laboratories project was carried out to develop and apply multiscale seismic methods for detecting and quantifying fractures in naturally fractured gas reservoirs.

APPROACH

This project took place within a 20-square-mile area at a producing gas field in the northwest part of the San Juan Basin in New Mexico. Three-dimensional surface seismic, multi-offset 9-C vertical seismic profiling (VSP), 3-C single-well seismic, and well-logging data were complemented by geologic/core studies to model, process, and interpret the data. The overall objective was to determine the seismic methods most useful in mapping productive gas zones.

ACCOMPLISHMENTS

Data from nearby outcrops, cores, and wellbore image logs suggested that natural fractures were probably numerous in the subsurface reservoirs at the site selected, and trend north-northeast/south-southwest despite the apparent dearth of fracturing observed in the wells logged at the site (Newberry and Moore wells). Estimated fracture spacing is on the order of 1–5 m in Mesaverde sandstones, less in Dakota sandstones. Fractures are also more frequent along fault zones, which in nearby areas trend between north-northeast/south-southwest and northeast-southwest—and are probably spaced a mile or two apart. The maximum *in situ* horizontal, compressive stress in the vicinity of the seismic test site trends approximately north-northeast/south-southwest. The data are few, but they are consistent.

The seismic data present a much more complicated picture of the subsurface structure. Faulting inferred from surface seismic had a general trend of SW–NE, but with varying dip, strike, and spacing. Studies of P-wave anisotropy from surface seismic showed some evidence that the data did have indications of anisotropy in time and amplitude. However, compared to the production patterns, there is little correlation with P-wave anisotropy. One conclusion is that the surface seismic reflection data are not detecting the complexity of fracturing controlling the production. Conclusions from the P-wave VSP studies showed a definite 3-D heterogeneity in both P- and S-wave characteristics. The analysis of shear-wave splitting from 3-D VSP data gave insight into the anisotropy structure with depth around the borehole. In the reservoir, the VSP shear-wave splitting data do not provide sufficient constraints against a model of lower symmetry than orthorhombic, so that the existence of more than one fracture set must be considered. It was also demonstrated that vertical transverse isotropy (VTI) and orthorhombic symmetry could be well defined from the field data by analyzing shear-wave splitting patterns. The detection of shear-wave singularities provides clear constraints to distinguish between different symmetry systems. The P-wave VSP common-depth-point (CDP) data showed evidence of fault detection at a smaller scale than the surface seismic showed, and in directions consistent with a complicated stress and fracture pattern. The single-well data indicated zones of anomalous wave amplitude that correlated well with high gas shows. The high amplitude single-well seismic data could not be explained by wellbore artifacts, nor could it be explained by known seismic behavior in fractured zones. Geomechanical and full-wave elastic modeling in 2- and 3-D provided results consistent with a complicated stress distribution induced by the interaction of the known regional stress and faults mapped with seismic methods.

SIGNIFICANCE OF FINDINGS

Sophisticated modeling capability was found to be a critical component in quantifying fractures through seismic data. Combining the results with the historical production data showed that the surface seismic analysis provided a broad picture consistent with production, but not detailed enough to consistently map complex structuring, which would allow accurate well placement. VSP and borehole methods show considerable promise in mapping the scale of fracturing necessary for more successful well placement. Integration of these methods at one field site enables investigators to give specific recommendations for the scale at which each method and fracture complexity would be appropriate.

ACKNOWLEDGMENTS

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THE REACTION KINETICS OF METHANE HYDRATE DISSOCIATION IN POROUS MEDIA

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RESEARCH OBJECTIVES

The objective of this study is to describe the kinetic dissociation of CH_4-hydrates in porous media, and to determine the corresponding kinetic parameters. Knowledge of the kinetic dissociation behavior of hydrates can play a critical role in evaluating the gas production potential of gas-hydrate accumulations in geologic media.

APPROACH

We analyzed data from a sequence of tests of CH_4-hydrate dissociation by means of thermal stimulation. These tests had been conducted on sand cores partially saturated with water, hydrate, and CH_4 gas, and contained in an x-ray-transparent aluminum pressure vessel. The pressure, volume of released gas, and temperature (at several locations within the cores) were measured. To avoid misinterpreting local changes as global processes, x-ray computed tomography scans provided accurate images of the location and movement of the reaction interface during the course of the experiments. After first determining the thermal properties of the hydrate-bearing medium, we obtained estimates of the kinetic parameters of the hydration reaction in porous media by means of inverse modeling (history matching) of the laboratory data, using the TOUGH-Fx/Hydrate code. Comparison of the results from the hydrate-bearing porous media cores to the known kinetic parameters of dissociation of pure CH_4-hydrate samples provided a measure of how the porous medium affected the kinetic reaction.

ACCOMPLISHMENTS

This is the first-ever determination of the kinetic parameters of hydrate dissociation in porous media. The excellent agreement between observations and numerical predictions validated the kinetic parameters determined through the inversion process, confirmed the hypothesis of their intrinsic character (and, thus, of their invariant values), provided increased confidence in (and further verification of) the numerical model used to describe the hydrate behavior in porous media, and indicated that the thermal conductivity model (developed as part of a related study) was not inconsistent with the overall system behavior.

SIGNIFICANCE OF FINDINGS

Knowledge of the kinetic rate of dissociation for gas hydrates is of critical importance in predicting the rate of gas production from natural hydrate accumulations, because it can provide an estimate of their technical and economic viability as potential energy sources.
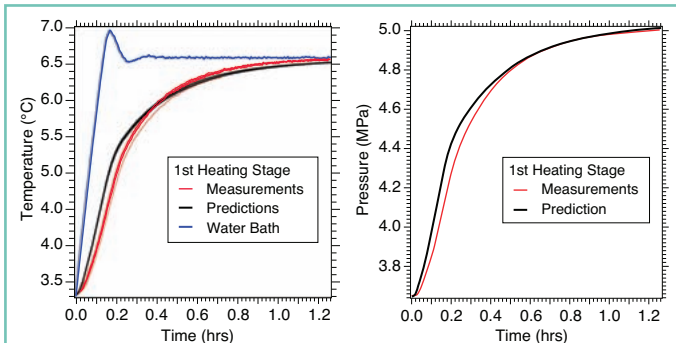

Figure 1. Comparisons between the evolution of the observed and predicted (based on the new estimates of kinetic dissociation) temperature and pressure in the hydrate-bearing core samples

RELATED PUBLICATIONS

Kneafsey, T., L. Tomutsa, G.J. Moridis, Y. Seol, B. Freifeld, C.E. Taylor and A. Gupta, Methane hydrate formation and dissociation in partially saturated sand—Measurements and observations. Proceedings of the 5th International Conference on Gas Hydrates (in press), Trondheim, Norway, June 13–16, 2005. Berkeley Lab Report LBNL-57300.

Moridis, G.J., Y. Seol, and T. Kneafsey, Studies of reaction kinetics of methane hydrate dissociation in porous media. Proceedings of the 5th International Conference on Gas Hydrates (in press), Trondheim, Norway, June 13–16, 2005. Berkeley Lab Report LBNL-57298.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

A Similarity Solution for Gas Production from Dissociating Hydrate Accumulations

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RESEARCH OBJECTIVES

The main objective of this study is to demonstrate that the problem of single-well gas production from dissociating hydrate-bearing geologic systems accepts a similarity solution. Such solutions are invariant when plotted against the similarity variable r^2/t; can form the basis of simplified, yet robust, graphical methods to estimate gas production from natural gas hydrate accumulations; and can serve as a tool to test the validity and accuracy of numerical simulators.

APPROACH

This study was motivated by the realization that there is a direct analogy between the phases of a pure H_2O system and a composite CH_4-H_2O hydrate system. Following the approach used in the development of the H_2O-based systems, we used the Boltzman transformation to reduce the partial differential equations (PDEs) of fluid flow and heat transfer in a hydrate-bearing geologic system, the boundary conditions, and the initial conditions into a set of ordinary differential equations (ODEs) of a form entirely consistent with prior similarity solutions. The transformation was conducted without any thermophysical simplifications or reduction in the strong nonlinearities of the PDEs. To prove the existence of a similarity solution, the ability to transform the original equations into a form known to accept a similarity solution is a necessary and sufficient condition. Thus, it is not necessary to solve the transformed system of equations; rather, it suffices to solve the original (coupled and strongly nonlinear) PDEs, and to demonstrate the invariance of any of the parameters (e.g., pressure, temperature, phase saturations) with respect to the similarity variable $r/t^{1/2}$.

ACCOMPLISHMENTS

Using the TOUGH-Fx/Hydrate numerical simulator of system behavior in hydrate-bearing geologic media, we demonstrated that the problem of gas production from natural hydrate accumulations admits a similarity solution. We established that such similarity solutions apply to all methods of hydrate dissociation (i.e., depressurization, thermal stimulation, and the effect of inhibitors), both individually and in any combination.

SIGNIFICANCE OF FINDINGS

Because the problem admits a similarity solution, the distributions of any of the variables (e.g., pressure, temperature, phase saturation) are invariant when plotted against r^2/t. Therefore, a single set of results is sufficient to describe system behavior and performance at any time.

The similarity solution can provide a simple and robust tool for evaluating the production potential of hydrate deposits. To accomplish this, we can develop simple graphical solutions for very complex problems by obtaining a family of similarity graphs for different conditions, thus avoiding lengthy numerical simulations.

Additionally, because we showed that the hydrate problem has a similarity solution, any numerical solution must be invariant when plotted against r^2/t. This is a robust tool for evaluating the accuracy of any numerical simulator of hydrate behavior. If the simulator is inaccurate, then the solutions at different times will not coincide.
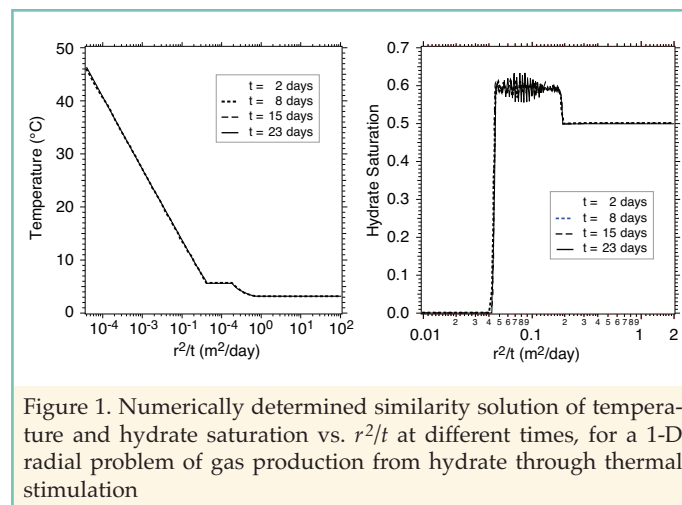

Figure 1. Numerically determined similarity solution of temperature and hydrate saturation vs. r^2/t at different times, for a 1-D radial problem of gas production from hydrate through thermal stimulation

RELATED PUBLICATION

ACKNOWLEDGMENTS

SLOT-SHAPED BOREHOLE BREAKOUT WITHIN WEAKLY CEMENTED SAND UNDER ANISOTROPIC STRESSES

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RESEARCH OBJECTIVES

Boreholes drilled within weakly cemented sand can suffer excessive sand production that may hinder, or even stop, production of oil—and ultimately cause collapse. Further, in recent years, there has been increasing evidence of a unique, slot-shaped borehole failure within weak, high-porosity sandstones, which may have a significant impact on the stability and sand production of boreholes.

The primary objectives of this research are: (1) to establish quantitative relationships between grain-scale properties of weakly cemented sand and macroscopic properties such as failure mode and rock strength; (2) to understand the process and mechanism of fracture formation and failure of a borehole in a realistic stress and flow environment; and (3) to develop a predictive capability for borehole stability and sand production, through a series of laboratory experiments.
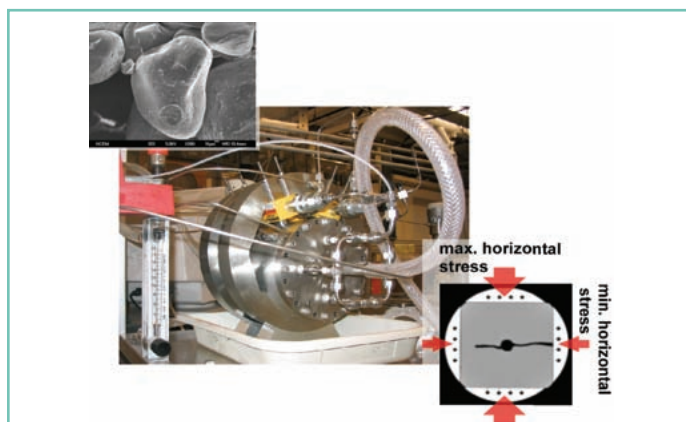

Figure 1. Block samples of weakly cemented sand (upper left, SEM photograph. Sand grain size~150 micrometers), containing a single borehole, are compressed anisotropically within a portable "true-triaxial" cell with fluid circulation through the borehole (middle). A slot-shaped borehole breakout develops in the direction perpendicular to the maximum horizontal stress direction around the borehole (lower right, x-ray CT image). The diameter of the borehole is approximately 1 cm (0.39 inches).

APPROACH

Because field cores of weakly cemented rocks are difficult to recover from oil and gas reservoirs, we developed a new laboratory technique to fabricate weakly cemented synthetic sandstone samples for our experiments. Using synthetic samples also allowed us to conduct parametric studies for a range of controlled sample properties, including the strength of intergranular bonds and porosity. These samples are made of pure quartz sand cemented together by a soda-lime glass micropowder melted under a high temperature. We also developed a "true-triaxial" loading cell (loads can be applied in the three perpendicular directions independently), capable of circulating fluid at a controlled rate through a borehole drilled in a rectangular block-shaped sample (3 inches x 3 inches x 6 inches).

ACCOMPLISHMENTS

Using the synthetic sandstone samples and the "true-triaxial" loading cell, we successfully produced a slot-shaped borehole breakout within the samples under anisotropic stresses and with fluid flow through the borehole (Figure 1). Experiments were conducted for a range of sample strength, borehole fluid flow rate, and stress anisotropy around the borehole axis. After each experiment, the geometry of the resulting breakout was examined via x-ray CT.

The results of the experiment showed that the width of the breakout decreased with increasing intergranular cohesion and strength of the samples, possibly because a larger zone of damage (process zone) formed near the edge of a breakout for weaker samples, which was subsequently washed away by the fluid flow. Further, for stronger samples, the growth of the breakout was rapid and catastrophic, while weaker samples exhibited the slow, stable growth of a breakout.

SIGNIFICANCE OF FINDINGS

Slot-shaped borehole breakout within well-cemented sandstone is commonly believed to form when the rock undergoes local compaction at the leading edge of the breakout, resulting in crushing of sand grains. In contrast, the slot failure within weakly cemented sand involves little grain failure, which indicates that compaction is not necessarily a critical mechanism of the failure. This indicates that the slot-shaped failure can occur at low stresses that do not involve grain crushing. Further, a numerical stress analysis based on a static boundary-element method indicates that, as long as the produced debris can be removed from the edge of the breakout, the growth of the slot-shaped breakout cannot be stopped, since the stress concentrations at the breakout-tip increases monotonically with the breakout length.

RELATED PUBLICATION

Nakagawa, S., and L.R. Myer, Mechanical and acoustic properties of weakly cemented granular rocks. 38th U.S. Rock Mech. Symp., Washington, DC, 3–10, 2001. Berkeley Lab Report LBNL-50814.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

Characterizing Thermal and Hydrological Properties of Hydrate-Bearing Sediments

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RESEARCH OBJECTIVES

Predicting natural gas recovery from reservoirs containing gas hydrates requires knowledge of both the reservoir properties and the properties and processes of hydrate dissociation. The main objective of this study is to perform laboratory tests to determine the thermal and physical properties of hydrate-bearing porous media, including thermal conductivity, kinetic parameters, and relative permeability.
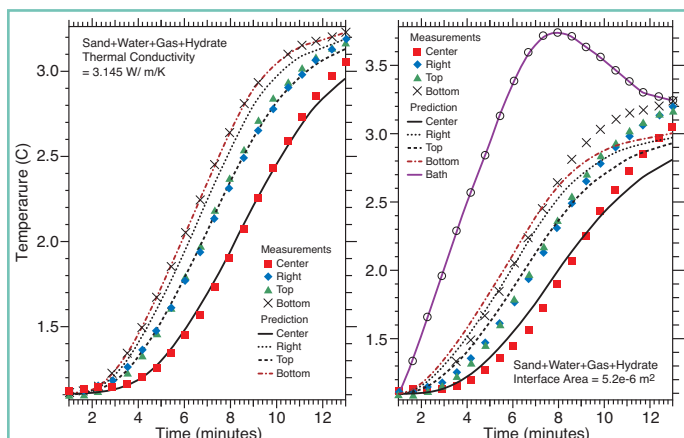

Figure 1. Calibration and parameter determination of the hydrate-bearing sand/water/gas/hydrate system (symbols represent measurements, lines represent model predictions)

APPROACH

To estimate thermal conductivity and kinetic parameters, we formed and dissociated methane hydrate in partially water-saturated sand contained in an x-ray-transparent aluminum pressure vessel. The sediment/hydrate sample was subjected to either thermal perturbations within the hydrate stability zone, or thermal or pressure perturbations leading to dissociation. History matching and inverse modeling with iTOUGH2 and TOUGH-Fx/Hydrate were performed to estimate the properties.

New laboratory tests were performed to estimate the relative permeability of hydrate-bearing porous media using a transient technique. Inverse modeling using iTOUGH2 was performed to optimize relative permeability curves, so as to provide saturation profiles that best match the x-ray computed tomography data.

ACCOMPLISHMENTS

Inverse modeling analysis of the experiments has provided needed estimates of the thermal properties and kinetic parameters of hydrate dissociation in porous media. We numerically inverted the thermal response of the system with and without hydrate, and determined the thermal conductivities of the sand/water/gas system and the sand/water/gas/hydrate system. The thermal conductivity of the system with hydrate exceeded that of the same sample prior to hydrate formation, in spite of the similar thermal conductivities of water and hydrate.

Using the thermal conductivities, we determined intrinsic rate constants and the activation energy of methane-hydrate-dissociation reactions by means of inverse modeling. The good agreement between numerical predictions and observations of pressure, temperature, and methane releases validated the parameters determined through the inversion process. Comparison of the results from the hydrate-bearing porous media to pure methane-hydrate samples has provided an initial measure of the effect of porous media on the kinetics of hydrate dissociation. The relative permeability measurements are in progress.

SIGNIFICANCE OF FINDINGS

Because of the strongly endothermic nature of hydrate dissociation and the importance of heat transfer, knowledge of the reaction kinetics and thermal properties of hydrate-bearing geological media is of critical importance to reliably predicting the gas production potential of natural gas hydrate deposits. These measurements and complementary modeling techniques should provide useful clues for understanding how natural gas can be produced from hydrate-bearing reservoirs.

RELATED PUBLICATIONS

Kneafsey, T.J., L. Tomutsa, G.J. Moridis, Y. Seol, B. Freifeld, C.E. Taylor, A. Gupta, Methane hydrate formation and dissociation in a partially saturated sand—Measurement and observations. In: 5th International Conference on Gas Hydrates, Trondheim, Norway, 2005. Berkeley Lab Report LBNL-57300.

Moridis, G.J., Y. Seol, T.J. Kneafsey, Studies of reaction kinetics of methane hydrate dissociation in porous media. In: 5th International Conference on Gas Hydrates, Trondheim, Norway, 2005. Berkeley Lab Report LBNL-57298.

ACKNOWLEDGMENTS

A New Analytical Solution for Migration of Sorbing Solute Tracers in Fractured Porous Media

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RESEARCH OBJECTIVES

The transport of chemicals or heat in fractured reservoirs is strongly affected by the fracture-matrix interfacial area. In water-saturated reservoirs, because molecular diffusion is orders of magnitude smaller than that in gas-dominated reservoirs, the tail of a breakthrough curve (BTC) is usually too weak to be practically useful as a characterization tool for determining the interfacial area. However, recent studies suggest that reversibly sorbing solute tracers can generate strong tails in BTCs that may allow a determination of such an area. To theoretically explore such a useful phenomenon, this paper develops an analytical solution for BTCs in slug-tracer tests within a water-saturated fractured reservoir.

APPROACH

We assume that the system has a single set of identical plane, parallel fractures with uniform fracture spacing and aperture, and that solute tracer is uniformly injected into the fractures at constant pore velocity and tracer concentration. Taking advantage of symmetry, we restrict the solution to an elementary part of the system (one-half of a fracture and its adjacent matrix block). The aperture is assumed much smaller than the length of the fracture, and transport in the fracture is assumed to be one-dimensional along the fracture. We ignore any tracer decay and treat the diffusive mass flux across the fracture-matrix interface as a sink/source term in the mass conservation equation for the fracture. We assume that transport in the matrix is only through diffusion (D is the diffusion coefficient) perpendicular to the interface, and that diffusion along the fracture is negligible compared with advection. Reversible sorption in the matrix is accounted for by a retardation factor, R. We derived the analytical solutions for tracer concentrations in the fracture and aperture, using the Laplace transform.

ACCOMPLISHMENTS

The solution reveals that BTCs in the fracture depend on four characteristic times: the tracer injection time, the travel time to the observation point, the across-fracture time (proportional to DR), and the across-matrix time (proportional to D/R). Since the first two times are known in a field test, and the last time only affects BTCs in the fracture for a fracture spacing on the order of centimeters, the across-fracture time is the only control factor on BTCs in most practical cases. This solution theoretically proves the numerical finding that BTCs depend only on the product, DR. A comparison of the analytical solution with the numerical (TOUGH2) solution is given in Figure 1, which shows excellent agreement for three different retardation factors.

SIGNIFICANCE OF FINDINGS

The analytical solution theoretically verifies an important finding, i.e., the retardation factor has the same effect as that of the diffusion coefficient. Although the diffusion coefficient is practically restricted, a wide range of retardation factors is practically available by using different chemical species as solute tracers. This equivalency thus provides the basis for using reversibly sorbing chemicals as tracers to test a fractured reservoir. In addition to its usefulness in verifying numerical codes, the analytical solution can also be useful as a screening tool for selecting solutes with appropriate sorption properties, and analyzing field data under simplified conditions. Such analysis can inversely estimate the two important parameters: the average fracture porosity and fracture spacing, from which the all-important fracture-matrix interfacial area per unit reservoir volume may be obtained.

RELATED PUBLICATION

Shan, C., and K. Pruess, An analytical solution for slug-tracer tests in fractured reservoirs. Water Resour. Res. (in press), 2005. Berkeley Lab Report LBNL-57285.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

Frequency-Dependent Asymptotic Analysis of Seismic Reflection from a Fluid-Saturated Medium

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RESEARCH OBJECTIVES

In this project, a linear poroelasticity model is reviewed from the point of view of basic principles of flow in porous media. A low-frequency asymptotic analysis of this model is applied to interpreting the frequency-dependent reflection coefficient component at low-frequency ranges.

The developed approach targets frequency-dependent analysis of seismic data from different types of hydrocarbon reservoirs, at both exploration and development stages. A practically important objective of this research is to demonstrate how reservoir flow properties can be mapped using the obtained asymptotic reflectivity model.

APPROACH

We derive wave propagation equations from the basic principles of the theory of filtration, particularly to verify that both the filtration and poroelasticity theories have a common foundation. In addition, such an approach facilitates establishment of a relationship between seismic imaging attributes and hydraulic reservoir parameters.

Over the last fifty years, a significant effort has been spent on investigating the attenuation of Biot's waves. In many cases, the attenuation coefficient can be obtained in an explicit, but quite cumbersome, form. Computation of the reflection coefficient is even more complex. In this study, we obtain a simple asymptotic expression, in which the role of the reservoir fluid mobility is transparent. We focus on the simplest case of p-wave normal reflection. (Solutions for more complex situations are currently under development.)
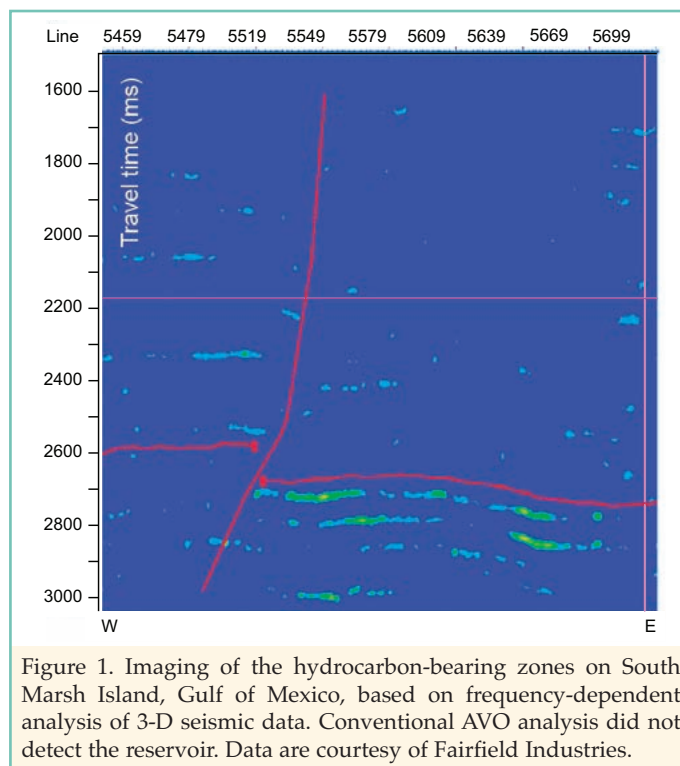
ACCOMPLISHMENTS

At low seismic frequencies, viscous fluid flow in pore space results in anomalous reflection of the signal. The reflection coefficient has been asymptotically expressed as the sum of constant and frequency-dependent components. The latter is proportional to the square root of the frequency of the signal, with the proportionality coefficient including the reservoir rock and fluid flow properties. The frequency-dependent component also includes a phase shift of the reflected wave.

In addition, we investigated the dependence of scaling on the dynamic Darcy's law relaxation time, which turns out to be linearly related to Biot's tortuosity parameter. This parameter must be very large to enter first-order asymptotic formulae. In addition, previously processed seismic data sets have been reviewed in the context of the results. In particular, 3-D seismic data from the offshore South Marsh Island reservoir have been successfully reevaluated to image hydrocarbon-rich formation layers (Figure 1).

SIGNIFICANCE OF FINDINGS

It has been demonstrated how frequency-dependent analysis can be successfully used for direct hydrocarbon indication and reservoir characterization. The analysis was performed on field seismic data from onshore and offshore hydrocarbon fields, with different properties for the reservoir rocks. Besides its use in imaging, frequency-dependent analysis based on low-frequency asymptotic scaling has great potential for quantitative reservoir characterization.

Figure 1. Imaging of the hydrocarbon-bearing zones on South Marsh Island, Gulf of Mexico, based on frequency-dependent analysis of 3-D seismic data. Conventional AVO analysis did not detect the reservoir. Data are courtesy of Fairfield Industries.

RELATED PUBLICATION

Silin, D.B., V.A. Korneev, G.M. Goloshubin, and T.W. Patzek, Low-frequency asymptotic analysis of seismic reflection from a fluid-saturated medium. Transport in Porous Media (in press), 2005. 58213

ACKNOWLEDGMENTS

Monitoring Waterflood Operations: Hall Method Revisited

Dmitriy Silin, R. Holtzman, T. W. Patzek, and J. L. Brink

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RESEARCH OBJECTIVES

The principal objective of this research is development of a robust and simple procedure for on-line monitoring of injecting well performance. An important requirement for the method is that it should not require interruption of regular field operations, and should be based on processing data routinely collected in waterflood operations. For example, such data may take the form of injection pressures and injection rates regularly recorded at each individual well as a time series. The results presented here are a part of the field-scale waterflood control system developed jointly by ChevronTexaco, with participation by the University of California, Berkeley, and Berkeley Lab.

APPROACH

Hall's method is a tool for evaluating injecting well performance. It is based on the assumption of radial steady-state flow. However, rigorous implementation of Hall's method requires information about the ambient reservoir pressure. In addition, it is assumed that the radius of influence is constant throughout the observation period. Neither of these parameters can be measured directly.

With this in mind, a series of forward simulations have been combined with analysis of injection pressures/injection rates data acquired from several hundred injection wells used in a waterflood project at the Lost Hills, California, diatomite oil field. The observations have been analyzed and interpreted using the model of steady-state flow. It turns out that inevitable fluctuations of injection pressures and rates can be used for estimation of an effective reservoir pressure, which in turn can be used for rigorous implementation of the Hall's method.

ACCOMPLISHMENTS

A new method called slope analysis has been proposed, based on analysis of Hall plot slope variations. This method produces an estimate of an apparent average reservoir pressure. As input, this method requires only time series of injection pressures and rates, which are routinely collected in the course of a waterflood. An automatic system of data acquisition has been implemented in the field, with measurements sent daily to a computer via the internet. As regular waterflood operations go on, the computer automatically processes the data, using a suite of custom-developed software tools.

The slope method has been verified both on synthetic and field data (Figure 1). It has been demonstrated that using the reservoir pressure estimates obtained by this method leads to correct interpretation of the Hall plot. At the same time, examples show that if such corrections are not done, the interpretation may be incorrect.

SIGNIFICANCE OF FINDINGS

The developed method is based on simple calculations and can be routinely applied for on-line injection-well performance monitoring. It can also be used in the petroleum industry, as well as in underground waste injection projects, where conventional well-performance evaluation procedures require interruption of operations and impose significant costs. The procedure has been incorporated into an injection control loop. Reservoir pressure maps, drawn based on slope analysis at multiple wells, make possible early detection of water breakthrough and reservoir compartmentalization.

RELATED PUBLICATION

Silin, D. B., R. Holtzman, T. W. Patzek, and J. L. Brink, Monitoring waterflood operations: Hall's Method revisited. SPE Paper 93879, Presentation at the 2005 SPE Western Regional Meeting held in Irvine, CA, U.S.A., March 30–April 1, 2005. Berkeley Lab Report LBNL-56928
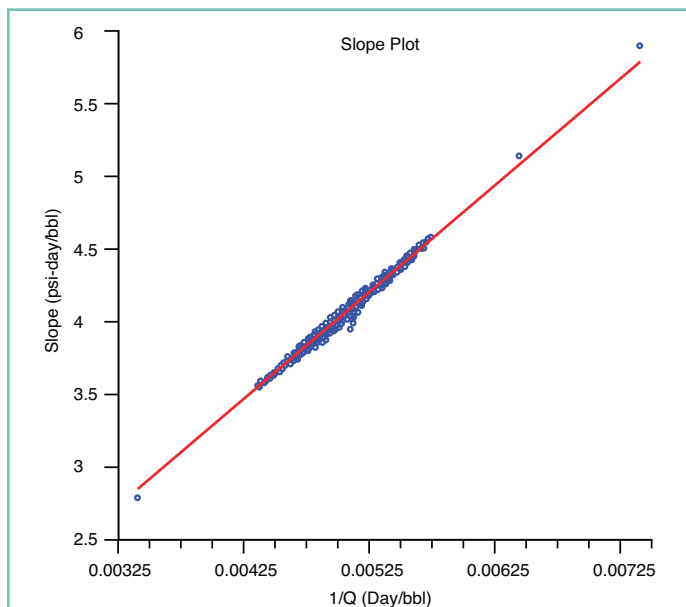
ACKNOWLEDGMENTS

Figure 1. The slope analysis yields the reservoir pressure estimate by fitting injection pressures/injection rates data in special coordinates.

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CRUSTAL DEFORMATION AND SOURCE MODELS
OF THE YELLOWSTONE VOLCANIC FIELD FROM GEODETIC DATA

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RESEARCH OBJECTIVES

The Yellowstone volcanic system is tectonically active, driven by intraplate extension at the eastern edge of the Basin-Range Province. This region has experienced the largest historic earthquake in the Basin and Range province, the M7.5 1959 Hebgen Lake Event. The Yellowstone caldera is the vertex of multiple north- to northwest-trending normal faults, and at this time the extent to which these faults interact with and control the magmatic and hydrothermal system is not known. The rapidly varying and complex deformation of the Yellowstone caldera raises a number of questions: What process drives this deformation? What is the role of pressure change and mass flux? If there is significant mass flux, what is the ratio of partial melt, hydrothermal fluids, and/or gases? What factors control fluid fluxes and pressure changes in the subsurface—magma bodies, caldera structure, geologic boundaries, intersecting faults?

APPROACH

To gain insight into the factors controlling surface deformation, we construct models of subsurface volume change that are compatible with surface deformation data. Our approach, based upon the inversion of multiple types of geodetic data (including interferometric synthetic aperture radar [InSAR—Figure 1a]), is exploratory in nature. That is, we allow for an arbitrary, three-dimensional distribution of subsurface volume change. The resulting pattern of subsurface volume change and source geometry can provide clues to the factors controlling observed surface deformation. With an improved understanding of the nature of the controlling features, we may then go on to construct more detailed and prescribed models for the sources of deformation.

ACCOMPLISHMENTS

The primary accomplishment is a model of subsurface volume change that may be interpreted in terms of subsurface fluid migration [Figure 1b]. The picture that emerges is of subsurface volume change that correlates with the resurgent domes, the Elephant Back fault zone, a north-trending fault zone related to the volcanic vents, and the extensive magma body beneath the caldera. These correlations suggests that such features control or at least influence deformation within the caldera, either as zones of mechanical weakness or as pathways for fluid flow, or both. There is evidence to support the role of both the Elephant Back fault zone and a north-trending central caldera fault zone in both internal deformation and fluid flow. We thus hypothesize that

the observed surface deformation within and adjacent to the Yellowstone caldera results from the interaction of an underlying, large-scale, crystallizing magmatic system and zones of weakness associated with crustal faults. In particular, large-scale pressure and mass changes within the magma body are focused into faults that act as narrow conduits or pathways for flow. It is the focused flow and pressure changes that give rise to the observed surface deformation.
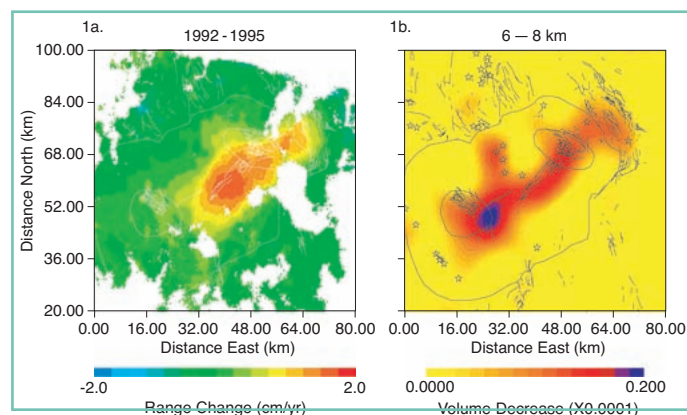

Figure 1a. Range change for the time interval 1992 to 1995. The color scale indicates the change in distance between the observation point in space and the surface of the Earth. Figure 1b. Volume change in the depth range is 6 to 8 km which is compatible with the observed range change.

SIGNIFICANCE OF FINDINGS

The findings are important because they further our understanding of how fluids interact with fault and fracture zones. Such interactions are critical to understanding hazards associated with volcanic regions and processes at work in geothermal fields. To date, little observational data are available on the interaction of fluids and faults/fractures in the earth. Most data are from idealized laboratory experiments or are interpreted using simple models. This work is the first step in an exploration of how geothermal fluids interact and influence faults and fracture zones. Understanding such interactions will help in finding new sources of geothermal energy.

ACKNOWLEDGMENTS

http://www-esd.lbl.gov/

Numerical Simulation of Injectivity Effects of Mineral Scaling and Clay Swelling in a Fractured Geothermal Reservoir

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RESEARCH OBJECTIVES

A major concern in the development of hot dry rock (HDR) and hot fractured rock (HFR) reservoirs is achieving and maintaining adequate injectivity, while avoiding the development of preferential short-circuiting flow paths. Rock-fluid interactions and associated mineral dissolution and precipitation effects could have a major impact on the long-term performance of these reservoirs.

APPROACH

We used recent European studies as a starting point to explore the chemically induced effects of fluid circulation in geothermal systems. We performed coupled thermal-hydrologic-chemical simulations in which the fractured medium was represented by a one-dimensional MINC model (multiple interacting continua). The nonisothermal multiphase reactive geochemical transport code TOUGHREACT was used for these simulations.

ACCOMPLISHMENTS

Injecting produced geothermal brines directly back into the reservoir results in mineral scaling. The reinjected, highly concentrated water from the geothermal reservoir can maintain clay density without swelling, but this limits the availability of water for injection. Mixing the produced geothermal water with large amounts of fresh water (1:4) can cause serious clay swelling when it is reinjected. However, modifying the injection water could avoid mineral scaling and enhance injectivity. Mitigating injection water chemistry could be an efficient way to achieve this objective. In this work, we added alkali to maintain a higher pH and let minerals (mainly calcite and quartz) precipitate out prior to reinjection. Using this modified injection water results in the injection rate gradually increasing, because of continual calcite and quartz dissolution. By mixing the reservoir water with appropriate amounts of fresh water
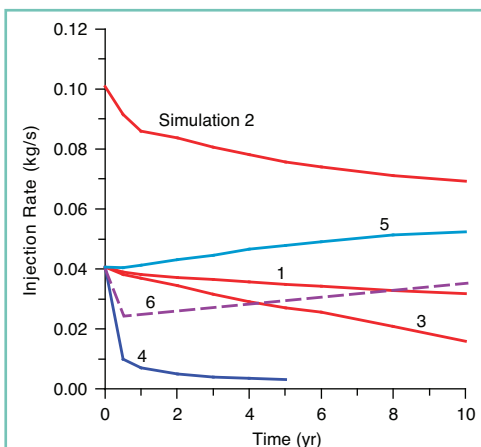

Figure 1. Injection rate of the fracture-matrix column with an area of 1 m². Simulation 1—base case; 2—over-pressure; 3—Verma-Pruess; 4—swelling; 5—pH 7; 6—mixing.

(1:1), together with adding alkali to let minerals precipitate out, we can reduce clay swelling and maintain injectivity. The well configuration and data for mineralogical composition in this study were taken from the European HDR research site, but the results and conclusions should be useful for other HFR reservoirs, because calcite and quartz are commonly present in geothermal systems.

SIGNIFICANCE OF FINDINGS

A detailed, quantitative understanding of processes and mechanisms, as presented in this research, is needed to develop reservoir management tools based on geochemistry. Such a novel approach should result in improvements in reservoir performance.

RELATED PUBLICATIONS

Xu, T, G. Zhang, and K. Pruess, Use of TOUGHREACT to simulate effects of fluid chemistry on injectivity in fractured geothermal reservoirs with high ionic strength fluids. In: Proceedings of the 30th Workshop on Geothermal Reservoir Engineering, Stanford University, California, January 31–February 2, 2005. Berkeley Lab Report LBNL-56532.

Xu, T, and K. Pruess, Numerical simulation of injectivity effects of mineral scaling and clay swelling in a fractured geothermal reservoir. Proceedings of Geothermal Resources Council 2004 Annual Meeting, Palm Springs, California, August 29–September 1, 2004. Berkeley Lab Report LBNL-55113.

ACKNOWLEDGMENTS

Injection of CO$_2$ with H$_2$S and SO$_2$ and Subsequent Mineral Trapping in a Sandstone-Shale Formation

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RESEARCH OBJECTIVES

Carbon dioxide (CO$_2$) injection into deep geologic formations can potentially reduce atmospheric emissions of greenhouse gases. Sequestering less-pure CO$_2$ waste streams (containing H$_2$S and/or SO$_2$) would require less energy than separating CO$_2$ from flue gas. The long-term interaction of these injected acid gases with shale-confining layers of a sandstone injection zone has not been well investigated. We therefore have developed a conceptual model of CO$_2$ injection with H$_2$S and/or SO$_2$ into a sandstone-shale sequence, using hydrogeologic properties and mineral compositions commonly encountered in Gulf Coast sediments of the United States.

APPROACH

We have performed numerical simulations of a 1-D radial well region considering sandstone alone, and a 2-D model using a sandstone-shale sequence under acid-gas injection conditions. The reactive fluid flow and geochemical transport simulator TOUGHREACT was used for these simulations. We considered the presence of organic matter, the kinetics of chemical interactions between the host rock minerals and the aqueous phase, and CO$_2$ solubility dependence on pressure, temperature, and salinity of the system.

Figure 1. Cumulative CO$_2$ sequestered by carbonate mineral precipitation at different times

ACCOMPLISHMENTS

The co-injection of H$_2$S, compared to injection CO$_2$ alone, does not significantly affect pH distribution and the mineral alteration pattern. The co-injection of SO$_2$ results in a different pH distribution and mineral alteration pattern. A zonal distribution of mineral alteration and formation of CO$_2$ and sulfur-bearing minerals has been observed in the simulations, which reflects the pH distribution. Co-injection of SO$_2$ results in a larger and stronger acidified zone (as low as a pH of 0.6). Corrosion and well abandonment problems will be a very significant issue for SO$_2$ injection. Most CO$_2$ is trapped by precipitation of ankerite and

dawsonite, with some in siderite. Using conditions and parameters presented in Xu et al. (2005), a CO$_2$ mineral trapping capability after 10,000 years can reach about 80 kg per cubic meter of medium. The CO$_2$ trapping capability depends on the primary mineral composition. For example, precipitation of siderite and ankerite requires Fe^{2+} supplied by the dissolution of primary iron-bearing minerals. Most of the sulfur is trapped by alunite precipitation, some by anhydrite, and some still smaller amount by pyrite. Precipitation of these sulfur-bearing minerals occurs primarily during the injection operation period, because the SO$_2$ inventory is very small (1 wt.% of CO$_2$ injected in the simulations). Adding acid gases leads to increases in porosity close to the well, caused by mineral dissolution, and decreases at distances, resulting from CO$_2$ trapping. The simulated mineral alteration pattern is generally consistent with available field observations of natural CO$_2$ reservoirs.

SIGNIFICANCE OF FINDINGS

The effects of co-injection of H$_2$S and SO$_2$ on CO$_2$ geological sequestration is evaluated, and CO$_2$ mineral trapping capability is estimated. The "numerical experiments" give a detailed understanding of the acid gas injection system.
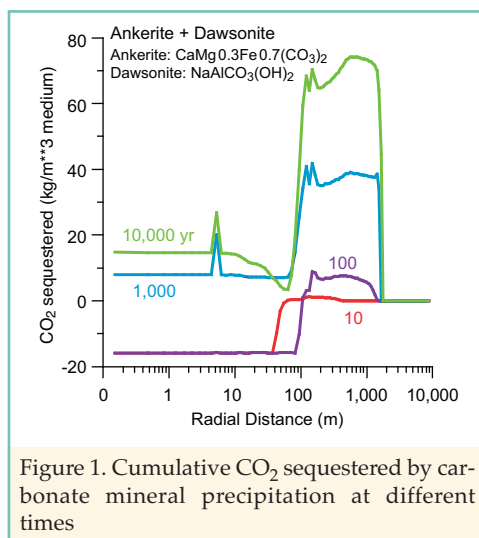
RELATED PUBLICATION

Xu, T, J. A. Apps, K. Pruess, and H. Yamamoto, Injection of CO$_2$ with H$_2$S and SO$_2$ and subsequent mineral trapping in sandstone-shale formation. Berkeley Lab Report LBNL-57426, 2005.

ACKNOWLEDGMENTS

TOUGHREACT
A COMPREHENSIVE NUMERICAL SIMULATOR FOR CHEMICALLY REACTIVE FLOWS

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RESEARCH OBJECTIVES

Reactive chemical transport occurs in many geologic systems and environmental problems, including geothermal systems, diagenetic and weathering processes, subsurface waste disposal, acid mine drainage remediation, contaminant transport, and groundwater quality. The objective of this work was to develop a publicly available comprehensive simulation tool for these processes.

APPROACH

The reactive transport simulator TOUGHREACT (Xu et al., 2004) has been developed by introducing reactive geochemistry into the existing framework of a nonisothermal, multicomponent fluid and heat flow simulator TOUGH2. Our modeling of flow and transport in geologic media is based on space discretization by means of integral finite differences (IFD). The IFD method yields a flexible discretization for geologic media, one that allows use of irregular grids. This is well suited for simulation of flow, transport, and fluid-rock interaction in multiregion heterogeneous and fractured rock systems. An implicit time-weighting scheme is used for the individual components of the model, consisting of flow, transport, and kinetic geochemical reactions. TOUGHREACT uses a sequential iteration approach. Chemical transport is solved on a component basis, with the resulting concentrations obtained from the

transport substituted into the chemical reaction model. The system of chemical reaction equations is solved on a gridblock basis by a Newton-Raphson iteration. The chemical transport and reaction equations are iteratively solved until convergence.

ACCOMPLISHMENTS

TOUGHREACT considers a wide variety of subsurface thermal-physical-chemical processes under various conditions of pressure, temperature, water saturation, ionic strength, and pH and Eh. It can be applied to one-, two-, or three-dimensional porous and fractured media with physical and chemical heterogeneity. The code can accommodate any number of chemical species present in liquid, gas, and solid phases. A variety of equilibrium chemical reactions are considered, such as aqueous complexation, gas dissolution/exsolution, cation exchange, and surface complexation. Mineral dissolution/precipitation can be simulated subject to either local equilibrium or kinetic controls, with coupling to changes in porosity and permeability. Chemical components can also undergo linear adsorption and radioactive decay. TOUGHREACT has been applied to a broad range of chemically reactive flow problems related to geothermal reservoir processes, groundwater protection, nuclear waste disposal, geologic storage of CO_2, and mining engineering. This software was released to the public through the DOE Energy Science and Technology Software Center in November 2004.

SIGNIFICANCE OF FINDINGS

TOUGHREACT is a very versatile simulator that can be applied to a broad range of environmental and resource problems of interest to DOE and industry.

RELATED PUBLICATION

Xu, T., E.L. Sonnenthal, N. Spycher, and K. Pruess, TOUGHREACT User's Guide: A simulation program for non-isothermal multiphase reactive geochemical transport in variable saturated geologic media. Berkeley Lab Report LBNL-55460, 2004.

ACKNOWLEDGMENTS

Figure 1. A schematic representation of a coupled thermal-hydrochemical problem solved by TOUGHREACT

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